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IDAHO PUBLIC
UTILITIES COMMISSION

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-03-13

IN THE MATTER OF THE APPLICATION OF
IDAHO POWER COMPANY
FOR AUTHORITY TO INCREASE ITS RATES AND
CHARGES FOR ELECTRIC SERVICE TO ELECTRIC
CUSTOMERS IN THE STATE OF IDAHO

DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
US DOE

February 20, 2004

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INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economic and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I worked as a staff economist at the North Carolina Utilities Commission. During my tenure at the Commission, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the Commission, I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate

Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978 I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, planning, pricing, and policy issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have submitted testimony and affidavits in more than 100 proceedings before state and federal agencies as an expert in cost of service, rate design, utility planning and operating practices, regulatory policy, and competitive market issues. These agencies include the Federal Energy Regulatory Commission (FERC), the General Accounting Office, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Arizona, Arkansas, Georgia, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. A listing of my participation in regulatory and court proceedings is presented in Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I AM APPEARING ON BEHALF OF THE FEDERAL EXECUTIVE AGENCIES (FEA), WHICH IS COMPRISED OF ALL FEDERAL FACILITIES SERVED BY IDAHO POWER COMPANY (IPC). TWO OF THE LARGER FEA FACILITIES ARE THE DEPARTMENT OF ENERGY'S IDAHO NATIONAL ENGINEERING AND ENVIRONMENTAL LABORATORY (DOE/INEEL) AND MOUNTAIN HOME AIR FORCE BASE. IPC SERVES DOE/INEEL UNDER A SPECIAL CONTRACT, AND SERVES THE BULK OF MOUNTAIN HOME AFB'S LOAD UNDER SCHEDULE 19 LARGE POWER SERVICE.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review IPC's proposed cost-of-service analyses (including pro forma adjustments) and related rates.
2. Identify any major deficiencies in the cost analyses and proposed rates and suggest recommended changes.

Q. WHAT SPECIFIC INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed IPC's application, testimony, exhibits, and responses to requests for information related to cost of service, revenue spread, and rate design issues.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. Cost-of-Service. IPC has proposed increasing base revenues by approximately $85.6 million (17.7 percent). In developing proposed rates

for its retail electric services, IPC first conducted a cost-of-service study for the test year ending December 31, 2003. In this cost analysis, IPC allocated and/or directly assigned its costs to functional segments of its retail electric business. The return component of IPC's costs reflects a requested 8.334 percent return on its retail jurisdictional rate base (using an 11.2 percent return on common equity).

In its cost study, IPC classified steam and hydro production costs as demand- and energy-related costs. IPC set the energy-related component of these costs equal to the Idaho jurisdictional load factor (55.26 percent), with the residual (1 – load factor) classified as demand-related costs. IPC asserted that the Commission has approved this classification scheme in prior rate cases. IPC classified transmission costs as demand-related costs and distribution costs as demand- or customer-related costs.[1]

In allocating demand-related production costs to major customer classes, IPC used a weighted 12-month coincident peak (W12CP) methodology. This methodology develops class allocation factors using the simple average of seasonal allocators derived from two different costing approaches—a traditional 12CP methodology and a methodology that weights class monthly coincident peak demands by IPC's estimated generation-related marginal cost. IPC claims that its marginal generation cost is positive (non-zero) only in the five months in which its projects capacity deficits (June, July, August, November, and December). IPC's estimated marginal generation cost in all other months is zero. As a result, the marginal cost component of IPC's demand-related generation cost allocation methodology is effectively a weighted 5CP methodology,

[1] Maggie Brilz, direct testimony at pages 8-9.

which, as noted earlier, is averaged with unweighted 12CP allocation factors to derive the class W12CP factors (that is, the D10 factors).[2]

IPC also used a W12CP methodology to allocate demand-related transmission costs. However, in developing the marginal cost component of these allocators, IPC's methodology focused on three months—June, July, and August—in which it projects transmission deficits. IPC's estimated marginal transmission cost was positive only in these three months and zero in the remaining nine months. IPC set the transmission cost class allocation factors (D13 factors) equal to the simple average of the unweighted and weighted class coincident demand components.

IPC allocated energy-related costs using allocation factors (E10 factors) reflecting monthly energy use by class weighted by IPC's estimated monthly marginal energy cost.[3] Unlike its estimates of marginal generation and transmission costs, IPC's estimated marginal energy cost is positive in each month. Finally, IPC allocated demand-related costs associated with distribution plant on the basis of coincident group peak demands, while it allocated customer-related distribution plant costs using average number of customers.

2. Revenue Spread. IPC spread its proposed revenue increase among rate classes using the following 4-step sequential approach:

- Identify sales revenue increases (or decreases) necessary to match total revenue from each class with IPC's estimated cost of serving the class as determined in IPC's class cost-of-service study (COSS).
- Set a 25-percent limit on the rate increase to Schedule 24 Irrigation Service customers instead of the 67.1 percent increase indicated by

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[2] IPC developed seasonal D10 factors (D10S and D10NS) to facilitate identifying seasonal cost responsibility.

[3] IPC also developed seasonal E10 factors (E10S and E10NS) to facilitate identifying seasonal cost responsibility.

the COSS.

- Hold revenues from the small unmetered classes (Schedules 4, 7, and 8) at test-year levels under present rates instead of decreasing revenues as indicated by the COSS results—that is, give no initial increase to these schedules.
- Spread the revenue shortfall caused by the 25-percent cap on Schedule 24's rate increase across all other schedules (including the unmetered classes and Special Contracts).

Two undesirable results occur under IPC's proposed revenue spread. First, the proposed spread perpetuates a $25 million annual subsidy paid to Irrigation customers by all other customer classes. That is, test-year revenue from IPC's proposed Irrigation Schedule 24 is slightly more than $25 million less than IPC's cost (as determined in its COSS) of serving this class.[4] IPC makes up this shortfall by overcharging all other customers. These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class much closer to cost of service than IPC has proposed. Second, IPC's revenue spread moves rates for Residential (Schedule 1) and Small General Service (Schedule 7) customers farther from cost of service and dramatically increases the subsidy these classes pay to Irrigation customers. This outcome is directly related to IPC's decision to set a 25-percent limit on the rate increase for Schedule 24 Irrigation customers.

3. Rate Design: Schedule 19. IPC has proposed major changes for Schedule 19 Large Power Service, which is applicable to customers with average billing demands of 1 MW or greater. Under IPC's proposal, Schedule 19

[4] As I demonstrate later in my testimony, the subsidy to Irrigation customers under present rates is also about $25 million.

will become a mandatory time-of-use rate with seasonal demand charges, an on-peak demand charge applicable in summer months (June-August), and energy charges differentiated both seasonally and diurnally. The proposed rate retains its Basic Charge (at an increased level), and, effective November 1, 2004, increases the power factor (going from 85 percent to 90 percent) at which the Power Factor Adjustment is triggered.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Approve IPC's weighted 12CP methodology to allocate demand-related production and transmission costs, and its weighted energy-related cost allocation methodology. Although the methodologies are not widely used, they appear to yield reasonable results.

2. Reject IPC's classification of hydro and steam production plant costs as demand- and energy-related costs. Instead, all hydro and steam production plant costs should be classified as demand-related costs. IPC's proposed classification scheme suffers from at least two defects. First, the scheme arbitrarily assumes that higher load factor customers receive a disproportionate share of the cheap energy benefits of baseload and intermediate capacity without paying a proportionate share of the higher capital costs of such capacity—particularly if demand-related capacity costs are allocated on the basis of peak demands. Second, the classification scheme arbitrarily assumes that IPC's system load factor somehow identifies the portion of generation plant costs that are

supposedly energy-related costs. Neither assumption is intuitively obvious or empirically supported in this case.

3. Reject IPC's proposed revenue spread. As I noted earlier, under IPC's proposal, Irrigation customers receive approximately $25 million in interclass revenue subsidies from other classes (especially Residential customers). The Commission should require IPC to spread the allowed revenue increase such that rates for Schedule 24 customers are increased by twice the average system rate increase. For example, if IPC receives its requested 17.68-percent increase in base revenues, the Irrigation class should get a 35.36-percent increase instead of the 25-percent increase that IPC proposed. The revenue shortfall after accounting for Schedule 24 revenues should be spread using the sequential step approach proposed by IPC and adopted by me. Details of how to implement this revenue spread approach are presented later in my testimony.

4. Adopt IPC's proposed Schedule 19 subject to the following condition. Specifically, the Commission should require IPC to prepare and file semiannual reports for the first year in which the rate is in effect concerning the implementation of the new TOU rate. At a minimum, these reports should include not only analyses of how well customers understand and respond to the new rate, but also detailed customer billing analyses that would enable the Commission to evaluate whether the rate is creating unanticipated and unacceptable hardship on some customers.

COST OF SERVICE

Q. DID IPC ESTIMATE ITS COST OF SERVING DIFFERENT CUSTOMER CLASSES?

A. YES. IPC CONDUCTED A DETAILED COST-OF-SERVICE STUDY USING DATA (ADJUSTED IN MANY CASES) FOR THE TEST YEAR ENDING DECEMBER 31, 2003. IN THIS COST ANALYSIS, IPC CLASSIFIED AND THEN ALLOCATED AND/OR DIRECTLY ASSIGNED ITS COSTS TO FUNCTIONAL SEGMENTS OF ITS RETAIL ELECTRIC BUSINESS. THE RETURN COMPONENT OF IPC'S COSTS REFLECTS A REQUESTED 8.334 PERCENT RETURN ON ITS IDAHO RETAIL JURISDICTIONAL RATE BASE (USING AN 11.2 PERCENT RETURN ON COMMON EQUITY).

Q. DID IPC FOLLOW REASONABLE GUIDELINES IN CONDUCTING ITS COST STUDY?

A. Yes. The cost study basically follows guidelines set in the NARUC *Electric Utility Cost Allocation Manual.*

Q. WHY IS THE REASONABLENESS OF A COST-OF-SERVICE METHODOLOGY IMPORTANT?

A. Cost of service identifies and assigns cost responsibility to customer classes. Specific rates can then be developed to recover each class' cost-based revenue requirement, resulting in prices that recover the utility's cost of service in an equitable and efficient manner. If the cost-of-service methodology does not allocate and assign cost responsibility in a reasonable manner, then interclass revenue subsidies are created and specific class rates are either over- or under-priced—thereby causing customers to make inefficient electricity investment and consumption decisions.

IPC has employed a reasonable cost-of-service methodology in this case to allocate and assign its costs to customer classes. However, as I discuss in more detail later, IPC deviated from the results of its cost study in assigning its simple average of the unweighted and weighted class coincident demand components.

Q. IS IPC'S WEIGHTED 12CP METHODOLOGY REASONABLE?

A. Yes. Although the methodology is not widely used, it appears to yield reasonable results. For example, I compared allocation factors derived under the W12CP methodology with allocation factors derived using three other methodologies—a weighted 5CP methodology (using coincident peak demands only in IPC's five capacity deficit months), an unweighted 12CP methodology, and an unweighted 5CP methodology. As shown in Exhibit DWG-1, class allocation factors under the W12CP are reasonably similar to allocation factors under the W5CP, 12CP, and 5CP methodologies for all classes except the Irrigation class.

Q. SHOULD THE COMMISSION ADOPT IPC'S W12CP ALLOCATION METHODOLOGY?

A. Yes.

Q. HOW DID IPC ALLOCATE ITS ENERGY-RELATED COSTS?

A. IPC used allocation factors (E10 factors) based on class monthly energy use weighted by IPC's estimated monthly marginal energy cost to allocate its energy-related costs.[6] Unlike its estimates of marginal generation and transmission costs, IPC's estimated marginal energy cost is positive in each month.

Q. IS THIS ALLOCATION METHODOLOGY CONSISTENT WITH THE W12CP METHODOLOGY IPC USED TO ALLOCATE DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS?

A. Yes. Both methodologies weight selected customer usage measures (peak demands and energy consumption) by relevant marginal costs. This approach reflects a reasonable attempt to introduce a dynamic costing element to IPC's

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[6] As I noted earlier, IPC developed seasonal E10 factors (E10S and E10NS) to facilitate identifying seasonal cost responsibility.

analysis of historical embedded costs. I recommend that the Commission approve IPC's proposed energy cost allocation methodology.

Q. HOW DID IPC CLASSIFY ITS HYDRO AND STEAM PRODUCTION PLANT COSTS?

A. In its cost study, IPC classified hydro and steam production costs as demand- and energy-related costs. IPC set the energy-related component of these costs equal to the Idaho jurisdictional load factor (55.26 percent), with the residual (1 – load factor) classified as demand-related costs.

Q. WHY DID IPC CHOOSE THIS CLASSIFICATION SCHEME?

A. IPC asserted that the Commission has approved this classification scheme in prior rate cases.[7]

Q. DO YOU AGREE WITH IPC'S CLASSIFICATION OF HYDRO AND STEAM PRODUCTION PLANT COSTS?

A. No. IPC's classification scheme rests on questionable assumptions, the validity of which is neither intuitively obvious nor empirically demonstrated in this case. Proponents of classifying production plant costs as energy-related costs typically rely on two key—but arbitrary—assumptions:

1. Higher load factor customers receive a disproportionate share of the cheaper energy benefits of baseload and intermediate capacity without paying a proportionate share of the higher capital costs of such capacity—particularly if demand-related capacity costs are allocated on the basis of peak demands.

2. IPC's system load factor somehow identifies the portion of generation plant costs that are supposedly energy-related costs.

Regarding the first assumption, baseload and intermediate plants are planned

[7] For example, see Idaho Public Utilities Commission, Case No. IPC-E-94-5, Order No. 25880 at page 26.

and designed to operate during more than peak demand periods, and higher load factor customers use energy from such plants in non-peak periods. However, whether higher load factor customers benefit disproportionately from cheaper baseload and intermediate plant energy is an empirical question that IPC has not addressed in this case. Moreover, in addressing this question, the method used to allocate energy-related costs must be considered. For example, if production plant costs are classified as energy-related costs and all energy costs are allocated on the basis of average energy use, then low load factor customers will likely receive the benefits of cheaper baseload and intermediate energy without paying a fair share of the capital costs for these plants.

Regarding the second assumption, using IPC's system load factor to identify the portion of production plant costs to classify as energy-related costs is totally arbitrary. For example, in IPC's last general rate case, the system load factor used to classify these costs was 67.57 percent,[8] versus a system load factor of 55.26 percent in this case. System load factor is an indicator of the relative use of supply resources (production plant) over time, and does not provide an economic or engineering rationale for classifying production plant costs.

Q. IF THE COMMISSION REJECTS YOUR RECOMMENDATION, HOW SHOULD THE ENERGY-RELATED COMPONENT OF PRODUCTION PLANT COSTS BE IDENTIFIED?

A. Let me reiterate—in my opinion, all production plant costs should be classified as demand-related costs.[9] Nonetheless, if part of IPC's production plant costs is classified as energy-related costs, I recommend setting the percentage of such plant costs classified as energy-related costs equal to the ratio of IPC's *weighted energy allocators in non-capacity deficit months*—that is, all months other than

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[8] Idaho Public Utilities Commission, Case No. IPC-E-94-5, Order No. 25880 at page 26.
[9] However, I have not conducted an empirical analysis to determine whether higher load factor customers benefit disproportionately from the cheaper energy of baseload and intermediate capacity.

June, July, August, November, and December—to the weighted 12-month allocator. This approach provides at least some intuitive linkage between the energy cost of production plant and high load factor energy use.

Q. WHAT IS THE RESULT OF USING THIS APPROACH?

A. Under this approach, 49.82 percent of IPC's hydro and steam production plant costs would be classified as energy-related costs. This percentage is derived as follows:

- In IPC's Exhibit No. 40, page 5, sum the weighted retail jurisdiction energy factors for the seven non-capacity deficit months—that is, all months other than June, July, August, November, and December. This value is 223,894,387.
- Divide 223,894,387 by 449,420,534—the sum of weighted retail jurisdiction energy use for all 12 months. The resulting value is 49.82 percent.

REVENUE SPREAD

Q. WHAT ARE INTERCLASS REVENUE SUBSIDIES?

A. Interclass subsidies reflect the amount by which revenue from a customer class exceeds or falls short of the class' cost responsibility, which is determined in IPC's class cost-of-service study. In general, a class receives (pays) an interclass subsidy if its rate revenue is less than (greater than) its assigned cost of service at the system average rate of return. The existence of large class rate of return differentials often indicates the presence of large interclass revenue subsidies.

Q. ARE RATE OF RETURN DIFFERENTIALS AND INTERCLASS REVENUE SUBSIDIES SIGNIFICANT UNDER PRESENT RATES?

A. Yes. Present rates for all classes except Irrigation customers are around $25 million above cost of service. (See Table 1 below and Exhibit DWG-2, page 1.) The rate of return (ROR) indexes for these above-cost classes range from 101 to 1,404. In contrast, rates for the Irrigation class (ROR index of minus 12) are more than $25 million higher than IPC's cost of service. Around 27 percent of the subsidy to Irrigation customers is currently paid by Residential customers. Since IPC's present rates have been in effect for about 10 years, a reasonable assumption is that the subsidy paid to Irrigation customers in that period may exceed $250 million.

Table 1. Interclass Subsidies Under Present Rates ($000)

Class	RORI	Subsidy
Residential	113	(6,850)
Sm Gen Service	101	(32)
Lg Gen Service	130	(7,942)
DTD	1,404	(1,490)
Lg Pwr Service	135	(4,956)
Irrigation	(12)	25,168
Unmetered	302	(333)
Muni St Lt	280	(429)
Traffic Lt	136	(25)
Micron	154	(1,889)
JR Simplot	175	(899)
DOE/INEEL	130	(324)
Total Retail	100	0

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-2, page 1.

Q. How did IPC spread the proposed revenue increase among customer classes?

A. IPC used a 4-step sequential approach to spread its proposed $85.6 million revenue increase (17.7 percent) among rate classes. More specifically, IPC:

1. Identified sales revenue increases (or decreases) that were necessary to match class revenues and cost of service as determined in IPC's class COSS. (See Exhibit DWG-2, page 2, and IPC Exhibit No. 61, page 2.)
2. Set a 25-percent limit on the rate increase to Schedule 24 Irrigation Service customers instead of the 67.1 percent increase indicated by the COSS. (See Exhibit DWG-2, page 3, and IPC Exhibit No. 61, page 3.)
3. Held revenues from the small unmetered classes (Schedules 4, 7, and 8) at test-year levels under present rates instead of decreasing revenues as indicated by the COSS results—that is, IPC gave give no initial increase to these schedules. (See Exhibit DWG-2, page 3, and IPC Exhibit No. 61, page 3.)
4. Spread the revenue shortfall caused by the 25-percent cap on the increase to Schedule 24 across all other schedules (including the unmetered classes and Special Contracts). (See Exhibit DWG-2, page 4, and IPC Exhibit No. 61, page 4.)

Q. DOES THIS INTERCLASS SUBSIDY SITUATION IMPROVE UNDER IPC'S PROPOSED REVENUE SPREAD?

A. No. IPC's proposed revenue spread perpetuates the $25 million annual subsidy currently paid to Irrigation customers by all other customer classes. That is, revenue under IPC's proposed Irrigation Schedule 24 is slightly more than $25 million less than IPC's cost of serving this class (as determined in its COSS). IPC makes up this shortfall by overcharging all other customers. These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class much closer to cost of service than IPC has proposed. In addition, IPC's revenue spread moves rates for Residential (Schedule 1) and Small General Service (Schedule 7) customers farther from cost of service and dramatically increases the subsidy these classes pay to Irrigation customers. (See Table 2 below and Exhibit DWG-2, page 4.) For example, the subsidy that Residential customers pay under present rates increases from $6.9 million to $12.1 million under IPC's proposed rates. This outcome is directly related to IPC's decision to set a 25-percent limit on the rate increase for Schedule 24 Irrigation customers.

Table 2. Interclass Subsidies Under IPC's Proposed Spread ($000)

Class	RORI	Subsidy
Residential	114	(12,121)
Sm Gen Service	115	(966)
Lg Gen Service	113	(5,886)
DTD	873	(1,482)
Lg Pwr Service	113	(2,980)
Irrigation	33	25,383
Unmetered	196	(266)
Muni St Lt	190	(358)
Traffic Lt	113	(15)
Micron	114	(832)
JR Simplot	111	(227)
DOE/INEEL	114	(251)
Total Retail	100	0

increase without imposing unjust and unreasonable increases on the Irrigation class. (See Table 3 below and Exhibit DWG-3, page 2.)

Table 3. Interclass Subsidies Under FEA's Proposed Spread ($000)

Class	RORI	Subsidy
Residential	110	(8,897)
Sm Gen Service	111	(709)
Lg Gen Service	110	(4,321)
DTD	863	(1,463)
Lg Pwr Service	109	(2,187)
Irrigation	49	19,138
Unmetered	192	(254)
Muni St Lt	184	(333)
Traffic Lt	110	(11)
Micron	110	(610)
JR Simplot	108	(167)
DOE/INEEL	110	(184)
Total Retail	100	0

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-3, page 2.

Q. DOES YOUR RECOMMENDED REVENUE SPREAD ELIMINATE INTERCLASS SUBSIDIES?

A. No. My recommended revenue spread only reduces the subsidies by about 25 percent. As shown in Table 3 above, Irrigation customers would still receive a subsidy of more than $19 million. Under my proposed spread, Residential customers would pay a subsidy of about $8.9 million, compared to $12.1 million under IPC's proposal.

Q. IF THE COMMISSION ALLOWS LESS THAN IPC'S REQUESTED SALES REVENUE INCREASE, HOW SHOULD THE APPROVED INCREASE BE SPREAD?

A. If IPC's retail base revenue increase is below 17.68 percent, I recommend using the same 4-step sequential approach that I used to develop the FEA revenue spread shown in Exhibit DWG-3.

RATE DESIGN: SCHEDULE 19

Q. HAS IPC PROPOSED A MAJOR REDESIGN OF SCHEDULE 19?

A. Yes. IPC has proposed major changes for Schedule 19 Large Power Service, which is applicable to customers with average billing demands of 1 MW or greater. Under IPC's proposal, Schedule 19 will become a mandatory time-of-use rate with seasonal demand charges, an on-peak demand charge applicable in summer months (June-August), and energy charges differentiated both seasonally and diurnally. The proposed rate retains its Basic Charge (at an increased level), and, effective November 1, 2004, increases the power factor (going from 85 percent to 90 percent) at which the Power Factor Adjustment is triggered.

Q. DO YOU HAVE ANY MAJOR CONCERN WITH THE PROPOSAL TO MAKE SCHEDULE 19 A TIME-OF-USE RATE?

A. Yes. While I do not object to the manner in which IPC designed the rate, I am concerned about the law of unintended consequences. IPC claims that the new rate design is revenue neutral.[10] However, if IPC's large commercial and industrial customers are not prepared to operate cost-effectively under the new rate, they may incur unexpected and unacceptably high bills for their energy use. In other words, customers will likely have to move up a learning curve to ensure

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[10] See IPC's response to Industrial Customers data request 1.2.

that they manage their electricity-intensive operations cost-effectively under the new rate. In my opinion, both IPC and the Commission should closely monitor how energy costs and consumption are affected by the new Schedule 19.

Q. SHOULD THE COMMISSION APPROVE IPC'S RECOMMENDED SCHEDULE 19?

A. Yes. The Commission should adopt IPC's proposed Schedule 19 subject to the following condition. Specifically, the Commission should require IPC to prepare and file semiannual reports for the first year in which the rate is in effect concerning the implementation of the new TOU rate. At a minimum, these reports should include not only analyses of how well customers understand and respond to the new rate, but also detailed customer billing analyses that would enable the Commission to evaluate whether the rate is creating unanticipated and unacceptable hardship on some customers.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-03-13

IN THE MATTER OF THE APPLICATION OF
IDAHO POWER COMPANY
FOR AUTHORITY TO INCREASE ITS RATES AND
CHARGES FOR ELECTRIC SERVICE TO ELECTRIC
CUSTOMERS IN THE STATE OF IDAHO

EXHIBIT NO. 401 OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
US DOE

February 20, 2004

Case No. IPC-E-03-13
Demand-Related Production Cost Allocators
12 Months Ending December 31, 2003

Allocation Factors by Methdology

Line			Allocation Methodology			
No.	**Tariff Description**	**Schedule**	**W12CP**	**W5CP**	**12CP**	**5CP**
	Rate Schedules					
1	Residential Service	1	0.3934	0.3805	0.4106	0.3849
2	Small General Service	7	0.0233	0.0228	0.0239	0.0227
3	Large General Service	9	0.2303	0.2253	0.2360	0.2262
4	Dusk/Dawn Lighting	15	0.0000	0.0000	0.0000	0.0000
5	Large Power Service	19	0.1279	0.1246	0.1322	0.1257
6	Irrigation Service	24	0.1670	0.1916	0.1355	0.1847
7	Unmetered Service	40	0.0009	0.0009	0.0010	0.0009
8	Municipal Street Lighting	41	0.0000	0.0000	0.0000	0.0000
9	Traffic Control Lighting	42	0.0005	0.0005	0.0006	0.0005
10	Subtotal		0.9433	0.9463	0.9398	0.9457
	Special Contracts					
11	Micron	26	0.0353	0.0343	0.0365	0.0346
12	J R Simplot	29	0.0100	0.0095	0.0106	0.0096
13	DOE	30	0.0114	0.0099	0.0130	0.0100
14	Subtotal		0.0567	0.0537	0.0602	0.0543
15	Total Idaho Retail Sales		1.0000	1.0000	1.0000	1.0000

Source: Factors taken or derived from IPC Exhibit 40 and IPC response to Staff 1.4 (Exhibit 40)

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EXHIBIT NO. 402 OF
DR. DENNIS W. GOINS
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February 20, 2004

Idaho Power Company
Case No. IPC-E-03-13
Revenue Allocation Summary
12 Months Ending December 31, 2003

IPC Present Rates - Proformed Normalized

Line No.	Tariff Description	Schedule	Average Customers	2003 Sales Normalized (MWh)	Rate Base	Present Sales Revenue	Mills per kWh	COS Rev Req @ 4.967%	Subsidy Received (Paid)	Cost of Service Index*	Rate of Return**	Rate of Return Index
	Rate Schedules											
1	Residential Service	1	335,605	4,141,393	642,356,205	214,289,412	51.74	207,438,937	(6,850,475)	103	5.62%	113
2	Small General Service	7	32,316	265,336	46,936,342	16,798,479	63.31	16,766,585	(31,894)	100	5.01%	101
3	Large General Service	9	17,415	3,014,427	330,066,571	107,669,011	35.72	99,727,085	(7,941,926)	108	6.43%	130
4	Dusk/Dawn Lighting	15	-	5,873	1,400,825	1,389,112	236.54	(100,638)	(1,489,750)	-	69.73%	1,404
5	Large Power Service	19	105	1,978,824	173,921,971	55,063,581	27.83	50,107,676	(4,955,905)	110	6.70%	135
6	Irrigation Service	24	13,517	1,620,931	276,495,493	60,291,580	37.20	85,459,912	25,168,332	71	-0.58%	(12)
7	Unmetered Service	40	1,224	16,055	2,027,979	907,691	56.54	574,384	(333,307)	158	14.98%	302
8	Municipal Street Lighting	41	124	17,879	2,915,750	1,809,265	101.20	1,380,559	(428,706)	131	13.92%	280
9	Traffic Control Lighting	42	58	9,384	833,049	284,147	30.28	259,411	(24,736)	110	6.78%	136
10	Subtotal		400,364	11,070,102	1,476,954,185	458,502,278	41.42	461,613,911	3,111,633	99		
	Special Contracts											
11	Micron ***	26	1	636,968	42,573,961	16,204,107	25.44	14,314,967	(1,889,140)	113	7.67%	154
12	J R Simplot	29	1	186,685	14,755,827	4,632,571	24.81	3,734,064	(898,507)	124	8.68%	175
13	DOE	30	1	203,084	13,159,556	4,622,413	22.76	4,298,426	(323,987)	108	6.47%	130
14	Subtotal		3	1,026,736	70,489,344	25,459,091	24.80	22,347,458	(3,111,633)	114		
15	Total Idaho Retail Sales		400,367	12,096,838	1,547,443,529	483,961,369	40.01	483,961,369	0	100	4.97%	100

* Assumes W12CP allocation methodology with ROR by class = 4.967% (system average at present rates)
Gross-up Rev Conversion Factor = 1.6420 (see IPC Exhibit 39 - Revenue Requirement Summary)
** IPC response to FEA 1.8c
*** Micron normalized revenue adjusted to reflect inclusion of annual O&M Facilities Charge Revenue.
Reference: IPC response to Staff 1.4, Exhibit 61

Idaho Power Company
Case No. IPC-E-03-13
Revenue Allocation Summary
12 Months Ending December 31, 2003

IPC Proposed Rates - Proformed Normalized at Cost of Service = 8.334% ROR

Line No.	Tariff Description	Schedule	W12CP Percent Change	W12CP COS Revenue Change	Revenue Allocation at W12CP COS	Mills per kWh	Rate of Return
	Rate Schedules						
1	Residential Service	1	13.38%	28,666,058	242,955,470	58.67	8.33%
2	Small General Service	7	15.26%	2,563,674	19,362,153	72.97	8.33%
3	Large General Service	9	9.57%	10,309,059	117,978,070	39.14	8.33%
4	Dusk/Dawn Lighting	15	-101.67%	(1,412,294)	(23,182)	(3.95)	8.33%
5	Large Power Service	19	8.46%	4,660,409	59,723,990	30.18	8.33%
6	Irrigation Service	24	67.10%	40,456,288	100,747,868	62.15	8.33%
7	Unmetered Service	40	-24.37%	(221,178)	686,513	42.76	8.33%
8	Municipal Street Lighting	41	-14.78%	(267,473)	1,541,792	86.24	8.33%
9	Traffic Control Lighting	42	7.51%	21,332	305,479	32.55	8.33%
10	Subtotal		18.49%	84,775,875	543,278,153	49.08	8.33%
	Special Contracts						
11	Micron	26	2.87%	465,070	16,669,177	26.17	8.33%
12	J R Simplot	29	-1.78%	(82,642)	4,549,929	24.37	8.33%
13	DOE	30	8.73%	403,609	5,026,022	24.75	8.33%
14	Subtotal		3.09%	786,037	26,245,128	25.56	8.33%
15	Total Idaho Retail Sales		17.68%	85,561,912	569,523,281	47.08	8.33%

Reference: IPC response to Staff 1.4, Exhibit 61

Idaho Power Company
Case No. IPC-E-03-13
Revenue Allocation Summary
12 Months Ending December 31, 2003

IPC Proposed Rates - First Pass Revenue Allocation

Line No.	Tariff Description	Schedule	First Pass Percent Change	First Pass Revenue Change	First Pass Revenue Allocation
	Rate Schedules				
1	Residential Service	1	13.38%	28,666,058	242,955,470
2	Small General Service	7	15.26%	2,563,674	19,362,153
3	Large General Service	9	9.57%	10,309,059	117,978,070
4	Dusk/Dawn Lighting	15	0.00%	0	1,389,112
5	Large Power Service	19	8.46%	4,660,409	59,723,990
6	Irrigation Service	24	25.00%	15,072,895	75,364,475
7	Unmetered Service	40	0.00%	0	907,691
8	Municipal Street Lighting	41	0.00%	0	1,809,265
9	Traffic Control Lighting	42	7.51%	21,332	305,479
10	Subtotal		13.37%	61,293,427	519,795,705
	Special Contracts				
11	Micron	26	2.87%	465,070	16,669,177
12	J R Simplot	29	-1.78%	(82,642)	4,549,929
13	DOE	30	8.73%	403,609	5,026,022
14	Subtotal		3.09%	786,037	26,245,128
15	Total Idaho Retail Sales		12.83%	62,079,464	546,040,833
16	Revenue Requirement Shortfall				23,482,448

Reference: IPC response to Staff 1.4, Exhibit 61

Idaho Power Company
Case No. IPC-E-03-13
Revenue Allocation Summary
12 Months Ending December 31, 2003

IPC Proposed Revenue Spread

Line No.	Tariff Description	Schedule	Final Percent Change	Final Revenue Change	Final Revenue Allocation	Mills per kWh	Subsidy Received (Paid)	Cost of Service Index*	Rate of Return**	Rate of Return Index
	Rate Schedules									
1	Residential Service	1	19.03%	40,787,315	255,076,727	61.59	(12,121,257)	105	9.48%	114
2	Small General Service	7	21.01%	3,529,668	20,328,147	76.61	(965,994)	105	9.59%	115
3	Large General Service	9	15.04%	16,195,086	123,864,097	41.09	(5,886,027)	105	9.42%	113
4	Dusk/Dawn Lighting	15	4.99%	69,304	1,458,416	248.34	(1,481,598)	--	72.75%	873
5	Large Power Service	19	13.88%	7,640,090	62,703,671	31.69	(2,979,681)	105	9.38%	113
6	Irrigation Service	24	25.00%	15,072,895	75,364,475	46.49	25,383,393	75	2.74%	33
7	Unmetered Service	40	4.99%	45,285	952,976	59.36	(266,463)	139	16.34%	196
8	Municipal Street Lighting	41	4.99%	90,266	1,899,531	106.25	(357,739)	123	15.81%	190
9	Traffic Control Lighting	42	12.87%	36,573	320,720	34.18	(15,241)	105	9.45%	113
10	Subtotal		18.20%	83,466,483	541,968,761	48.96	1,309,392			
	Special Contracts									
11	Micron	26	8.00%	1,296,710	17,500,817	27.48	(831,640)	105	9.52%	114
12	J R Simplot	29	3.12%	144,358	4,776,929	25.59	(227,000)	105	9.27%	111
13	DOE	30	14.16%	654,362	5,276,775	25.98	(250,753)	105	9.49%	114
14	Subtotal		8.23%	2,095,429	27,554,520	26.84	(1,309,392)			
15	Total Idaho Retail Sales		17.68%	85,561,912	569,523,281	47.08	0	100	8.33%	100

* Final Revenue Allocation / COS Rev Requirement @ 8.334%
** IPC response to FEA 1.8c
Reference: IPC response to Staff 1.4, Exhibit 61

STATE OF IDAHO
BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-03-13

IN THE MATTER OF THE APPLICATION OF
IDAHO POWER COMPANY
FOR AUTHORITY TO INCREASE ITS RATES AND
CHARGES FOR ELECTRIC SERVICE TO ELECTRIC
CUSTOMERS IN THE STATE OF IDAHO

EXHIBIT NO. 403 OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
US DOE

February 20, 2004

Idaho Power Company
Case No. IPC-E-03-13
Revenue Allocation Summary
12 Months Ending December 31, 2003

FEA Proposed Revenue Spread

Line No.	Tariff Description	Schedule	Final Percent Change	Final Revenue Change	Final Revenue Allocation	Mills per kWh	Subsidy Received (Paid)	Cost of Service Index*	Rate of Return**	Rate of Return Index
	Rate Schedules									
1	Residential Service	1	17.53%	37,563,441	251,852,853	60.81	(8,897,383)	104	9.18%	110
2	Small General Service	7	19.48%	3,272,744	20,071,223	75.64	(709,070)	104	9.25%	111
3	Large General Service	9	13.59%	14,629,588	122,298,599	40.57	(4,320,529)	104	9.13%	110
4	Dusk/Dawn Lighting	15	3.66%	50,871	1,439,983	245.20	(1,463,165)	--	71.95%	863
5	Large Power Service	19	12.44%	6,847,588	61,911,169	31.29	(2,187,179)	104	9.10%	109
6	Irrigation Service	24	35.36%	21,318,490	81,610,070	50.35	19,137,798	81	4.12%	49
7	Unmetered Service	40	3.66%	33,241	940,932	58.61	(254,419)	137	15.97%	192
8	Municipal Street Lighting	41	3.66%	66,258	1,875,523	104.90	(333,731)	122	15.30%	184
9	Traffic Control Lighting	42	11.44%	32,519	316,666	33.74	(11,187)	104	9.15%	110
10	Subtotal		18.28%	83,814,740	542,317,018	48.99	961,135			
	Special Contracts									
11	Micron	26	6.64%	1,075,520	17,279,627	27.13	(610,450)	104	9.21%	110
12	J R Simplot	29	1.81%	83,983	4,716,554	25.26	(166,625)	104	9.02%	108
13	DOE	30	12.71%	587,669	5,210,082	25.65	(184,060)	104	9.19%	110
14	Subtotal		6.86%	1,747,172	27,206,263	26.50	(961,135)			
15	Total Idaho Retail Sales		17.68%	85,561,912	569,523,281	47.08	0	100	8.33%	100

* Final Revenue Allocation / COS Rev Requirement @ 8.334%
** Relects Gross-up Rev Conversion Factor = 1.6420 (see IPC Exhibit 39 - Revenue Requirement Summary)